REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC") and the Canada Energy Regulator ("CER") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team.

Regulatory Law Chambers ("RLC") is a Calgary based boutique law firm, specializing in energy and utility regulated matters. RLC works at understanding clients' business objectives and develops legal and business strategies with clients, consistent with public interest requirements. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

IN THIS ISSUE:

ALBERTA COURT OF APPEAL

Fort McMurray Métis Local Council 1935 v Alberta Energy Regulator and Canadian Natural Resources Ltd., 2022 ABCA 179

Oil and Gas - Regulatory Appeal

In this decision, the Alberta Court of Appeal ("ABCA") approved the application from Fort McMurray Métis Local Council 1935 ("Fort McMurray Métis") who sought permission to appeal a decision by the AER that denied Fort McMurray Métis' request for a regulatory appeal. The AER had denied the request for regulatory appeal of the Horizon South Lease 24 project's approvals. The request was filed by Fort McMurray Métis under s. 38 of the *Responsible Energy Development Act* ("*REDA*").

The ABCA granted permission to appeal on the following questions:

1. Did the AER err in its interpretation of the statutory requirements for eligibility to submit a regulatory appeal under *REDA*?
2. Did the AER err by requiring too high a threshold burden to establish eligibility to appeal?

<u>Factual Background</u>

Canadian Natural Resources Limited ("CNRL") operates the Horizon Mine and the Joslyn Mine near Fort McMurray. On January 18, 2021, the AER approved CNRL's application to integrate the Joslyn Mine with its existing Horizon Mine operations (the "Integration Application"). The AER issued its approval decision without reasons determining that a hearing was not required.

In February 2021, Fort McMurray Métis applied to the AER for a regulatory appeal of the decision to approve the Integration Application. Fort McMurray Métis raised three grounds in the request for regulatory appeal before the AER.

1. The AER misapprehended the information provided by Fort McMurray Métis and, as a result, made conclusions that were not supported by the facts.
2. The AER misapplied the test established by the ABCA in *Dene Tha' First Nation v Alberta (Energy and Utilities Board)*, 2005 ABCA 68 by finding that more evidence was required for the AER to find that Fort McMurray Métis were directly and adversely affected.
3. The AER did not fulfill its public interest mandate by discarding the clear issue that Fort McMurray Métis have Aboriginal rights that may be impacted and have not been considered in the approval process.

The AER decided that McMurray Métis did not provide sufficient evidence to establish the required degree of location or connection between the proposed project and the impacts on their rights in the project's vicinity. The AER found that the integration approved by the decision did not create an additional magnitude of risk to make McMurray Métis directly and adversely affected. The approval did not involve a new project, new activities, or disturbance of any additional lands. The AER consequently denied Fort McMurray Métis' request for a regulatory appeal.

<u>Test for Permission to Appeal</u>

Fort McMurray Métis provided three grounds of appeal in its application for permission to appeal to the ABCA:

1. Did the AER err in its interpretation of the statutory requirements for eligibility to submit a regulatory appeal?
2. Did the AER err by requiring too high a threshold burden to establish eligibility to appeal?
3. Did the AER err by not considering the constitutionally protected Aboriginal rights at stake?

Analysis

To determine if any of the proposed grounds of appeal meet the test for permission to appeal, the ABCA reviewed the applicable statutory scheme and the AER's role in considering the rights of Aboriginal peoples when making decisions pursuant to an energy resource enactment. The ABCA may only consider the proposed grounds of appeal if they raise a question of law.

Do the Grounds of Appeal Raise Questions of Law?

The AER is mandated with providing for the efficient, safe, orderly and environmentally responsible development of energy resources in Alberta. *REDA* also sets out the AER's role in regulating the disposition and management of public lands, the protection of the environment, and the conservation and management of water concerning energy resource activities.

Ss. 39 and 40 of *REDA* allow the AER to conduct a regulatory appeal of its own decisions. The decision must be "appealable," and the request submitted by an eligible person in accordance with the requirements of s. 38(1).

The AER determined that the Fortis McMurray Métis was not an "eligible person" because it was not directly affected by the approval decision.

In reaching its decision, the ABCA referenced the matters of *Normtek Radiation Services Ltd v Alberta Environmental Appeal Board*, 2020 ABCA 456 ("*Normtek*") and *Coulas v Ferus Natural Gas Fuels Inc*, 2016 ABCA 332 ("*Coulas*"). In *Coulas*, the ABCA determined that the AER may have acted unlawfully in finding that the applicant's level of interest was insufficient to make her "directly and adversely affected" and determined that this constitutes a question of law. In *Normtek*, the ABCA found that "directly affected" needs to be interpreted broadly, as it is impossible to define every way in which a person could be directly affected.

The ABCA found that these two authorities indicate that the correct interpretation of an "eligible person" under section 36(b) of *REDA* can be a legal question and concluded that Fort McMurray Métis' grounds of appeal that relate to the AER's interpretation of "eligible person" and "directly affected" do raise a question of law.

The AER's Jurisdiction to Consider Aboriginal Rights

The ABCA considered the AER's role in assessing constitutional rights, the duty to consult, and the honour of the Crown in *Fort McKay First Nation v Prosper Petroleum Ltd*, 2020 ABCA 163 ("*Prosper*"). In *Prosper,* the ABCA held that the AER is a tribunal empowered to consider questions of law and that it has implied jurisdiction to consider issues of constitutional law as they arise. The AER, however, may not consider questions of law if there is a clear demonstration that the legislature intended to exclude such jurisdiction. The ABCA noted that when the "public interest" needs to be considered, the AER must apply the Constitution and ensure its decisions comply with s. 35 of the *Constitution Act, 1982*. A project authorization that breaches the constitutionally protected rights of Indigenous peoples will not serve the public interest.

In this application, the only question before the ABCA was if the Fort McMurray Métis was an "eligible person," which question does not raise any issues about the scope or interpretation of Fort McMurray Métis' constitutional rights. The ABCA held that the nature of Fort McMurray Métis' constitutional rights was not before the AER in this decision. Accordingly, the Court held that this ground of appeal does not raise a question of law.

Do the Grounds of Appeal Meet the Test for Permission to Appeal?

The ABCA was satisfied that the provided grounds of appeal meet the test for permission. Fort McMurray Métis raised a serious and important issue. The approval decision extends the operation of the former Joslyn Mine by 29 years, delaying reclamation and the eventual return of the site to the Fort McMurray Métis for at least a generation. Accordingly, the applicant was directly affected.

Conclusion

The ABCA granted leave to appeal on the questions of:

1. whether the AER erred in its interpretation of the statutory requirements for eligibility to submit a regulatory appeal under *REDA*; and
2. whether the AER erred by requiring too high a threshold burden to establish eligibility to appeal.

***Reference re Impact Assessment Act,* 2022 ABCA 165**

Reference - Division of Powers

In this decision, the Alberta Court of Appeal ("ABCA") determined that the *Impact Assessment Act* ("*IAA*" or "*Act*") and the *Physical Activities Regulations* (the "*Regulations*") are unconstitutional. The ABCA found that the *IAA* undermines the division of powers and the rights provided to the provinces to control the ownership and development of natural resources in their boundaries. Accordingly, the ABCA determined that the *IAA* is *ultra vires* Parliament.

Introduction

The Lieutenant Governor in Council asked for the ABCA's opinion on two questions:

1. Is Part 1 of *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, S.C. 2019, c. 28 unconstitutional, in whole or in part, as being beyond the legislative authority of the Parliament of Canada under the Constitution of Canada?
2. Is the *Physical Activities Regulations*, SOR/2019-285, unconstitutional in whole or in part by virtue of purporting to apply to certain activities listed in Schedule 2 thereof that relate to matters entirely within the legislative authority of the Provinces under the Constitution of Canada?

To answer these questions, the ABCA focused on the projects that would fall under the regulation of the *IAA* and the *Regulations*. The ABCA further considered the extent to which the provinces and Canada have individual and shared concerns about the environment and climate change.

The ABCA found that the *IAA* deprives Alberta and Saskatchewan, which together have the vast majority of oil and gas reserves in this country, of their constitutional right to exploit these natural resources. The ABCA noted that this deprivation, while the federal government continues to permit the import of hundreds of millions of barrels of oil into Canada from other countries, reintroduces the very discrimination both provinces understood to have ended, if not in 1930, then certainly by 1982.

Parliament has the authority to legislate to protect the environment. However, it must do so in accordance with the Constitution. The ABCA concluded that the subject matter of the *IAA* is properly characterized as "the establishment of a federal impact assessment and regulatory regime that subjects all activities designated by the federal executive to an assessment of all their effects and federal oversight and approval". When applied to intra-provincial designated projects, this subject matter does not fall under any heads of power assigned to Parliament but rather intrudes impermissibly into heads of power assigned to provincial Legislatures by the *Constitution Act, 1867*.

The ABCA, therefore, concluded that the *IAA* is *ultra vires* Parliament.

The Environment and the Division of Powers

The ABCA noted that the environment has not been assigned to the jurisdiction of either Parliament or provincial Legislatures under the *Constitution Act, 1867*, nor has the environment been allocated to the federal government under the national concern doctrine. Both levels of government may affect the environment but only within the legislative powers specifically assigned to each. The ABCA further noted that neither level of government has exclusive jurisdiction over environmental impact assessments. Like the environment more generally, impact assessments are not explicitly enumerated as a head of power under ss 91 or 92 of the *Constitution Act, 1867.*

The Purpose and Scope of the Resource Amendment Under S. 92A of the *Constitution Act*, 1867

Under s. 92A(1) of the *Constitution Act, 1867* each province may exclusively make laws in relation to (a) exploration for non-renewable natural resources in the province; (b) development, conservation, and management of non-renewable natural resources and forestry resources in the province; and (c) development, conservation, and management of sites and facilities in the province for the generation and production of electrical energy.

The ABCA noted that provincial jurisdiction over natural resources is "one of the mainstays of provincial power". Consequently, deciding the terms and conditions under which a project to exploit these natural resources will be constructed and operated goes directly to a province's power to decide how best to manage, and the conditions under which it will permit the development of, its natural resources.

Overview of Environmental Impact Assessment Legislation Federally

The *IAA* and the *Regulations* apply to and compel a comprehensive assessment and review of any activity anywhere in Canada designated in the Regulations (sometimes referred to as the "project list") or by Ministerial order.

The *IAA* is designed to assess proposed designated projects in their entirety. This is illustrated not only by the scope of purported federal effects but also by at least 20 different factors that must be considered. These range from changes to environmental, health, social, or economic conditions, to "the extent to which the designated project contributes to sustainability", to "the extent to which the effects of the designated project hinder or contribute to the Government of Canada's ability to meet its environmental obligations and its commitments in respect of climate change", to "the intersection of sex and gender with other identity factors" to "any other matter relevant to the impact assessment" that the Impact Assessment Agency of Canada ("Agency") requires to be taken into account.

The *IAA* and *Regulations* seek to regulate a number of activities primarily within exclusive federal jurisdiction. Importantly, however, designated projects also include intra-provincial activities otherwise within provincial jurisdiction such as mining, renewable energy, transportation, and oil and gas.

Section 7 of the *IAA* prohibits the proponent of a designated project, and that would include all intra-provincial designated projects, from doing "any act or thing in connection with the carrying out of the designated project, in whole or in part, if that act or thing may cause" any of the listed effects. The listed effects track almost word for word the definition of "effects within federal jurisdiction".

Under the *IAA*, Parliament has also regulated what it has defined as "direct or incidental effects" and what it characterizes as "adverse direct or incidental effects". Direct or incidental effects include effects that are directly linked or necessarily incidental to a federal authority's grant of a federal permit or approval that a designated project requires under other valid federal legislation to proceed. S. 8 of the *IAA* prohibits a federal authority from issuing a federal permit for a designated project unless a positive public interest determination has been made by the federal executive or unless no impact assessment is required.

There are three main phases to the impact assessment process:

First, there is the planning phase: A proponent of a designated project provides the Agency with a description of the project that must include information prescribed by regulation. If the Agency decides a designated project requires an impact assessment, it issues a notice of commencement outlining the information and studies needed to conduct the assessment.

Second, there is the impact assessment phase. This begins with the proponent collecting the requested information and completing the required studies that it provides to the Agency. An assessment of the designated project is then carried out, either by the Agency or, in cases where the Minister is of the view it is in the public interest, a review panel. The potential effects of a designated project are assessed, after which a report is prepared.

Third, there is the decision phase: The Minister or Governor in Council is required to make a public interest determination with respect to the designated project which must be based on the report and other mandatory factors. If the public interest determination is positive, the Minister or Governor in Council must also determine what conditions will be imposed. The Minister must then issue a "decision statement" to the proponent informing the proponent of the public interest determination made by either the Minister or Governor in Council and the reasons for it and, if applicable, any conditions that must be complied with by the proponent.

If the public interest determination is not positive the proponent continues to be prohibited from proceeding with the designated project if it may cause any of the purported federal effects. This effectively prohibits the proponent from proceeding since the negative public interest determination constitutes a finding by the federal executive that the designated project may cause such purported federal effects.

The ABCA found that the provisions of the *IAA* and the *Regulations* accordingly require that: unless and until the federal executive determines that an intra-provincial designated project is in the public interest, the proponent of that project cannot proceed with it, full stop.

<u>Division of Powers</u>

Reviewing legislation for validity on federalism grounds involves a two-stage analytical approach: (1) characterization; and (2) classification. First, the subject matter (or "pith and substance") of the challenged legislation must be characterized. Characterization requires looking at both the purpose of the law and its effects. Second, that subject matter must be classified by assigning it to federal and provincial heads of power. But since not all powers are limited to a class of subjects, the Court's task is more accurately described as determining "whether the subject matter of the challenged legislation falls within the head of power being relied on to support the legislation's validity".

A statute and related regulations will be considered together for purposes of constitutional characterization where the regulations give "concrete meaning and content to the statute and [are] indispensable to its classification". The ABCA found that the *Regulations* constitute an integral part of the legislative scheme. The *IAA* provides a statutory framework; the *Regulations* make that framework operative. It is the *Regulations* that list the designated projects subject to the federal environmental impact assessment. The ABCA accordingly found that the *IAA* and *Regulations* should be considered together to properly characterize and classify the legislative scheme as a whole.

<u>The First Stage: Characterization – What is the "Matter" of the *IAA*?</u>

The ABCA found that the "pith and substance", or the "matter" of the *IAA* is: "the establishment of a federal impact assessment and regulatory regime that subjects all activities designated by the federal executive to an assessment of all their effects and federal oversight and approval". This subject matter, and any variation on it, including the "establishment of a federal impact assessment and regulatory regime that subjects all intra-provincial activities designated by the federal executive to an assessment of all their effects and federal oversight and approval", intrudes fatally into provincial jurisdiction and the provinces' proprietary rights as owners of their public lands and natural resources.

The ABCA noted that Canada's Constitution does not permit this hollowing out of provincial powers. The ABCA summarized the findings underpinning its conclusion that the *IAA* and *Regulations* amount to federal overreach as follows:

1. The *IAA* compels an intra-provincial designated project to undergo a wide-ranging impact assessment and subjects the project to regulation from inception to completion merely because the federal executive has designated it as a designated project.

2. The *IAA* gives the federal executive the unilateral right to make that designation even where the federal government has no decision-making authority *vis à vis* that project under other valid and applicable federal legislation.
3. The *IAA*'s self-defined "effects within federal jurisdiction" includes effects not within Parliament's jurisdiction when applied to intra-provincial designated projects, namely, the incidental effects of provincial laws (authorizing such projects) on a federal head of power, effects not linked, or not sufficiently linked, to a federal head of power and effects that do not even qualify as significant.
4. The *IAA* prohibits a proponent of an intra-provincial designated project from any conduct that is otherwise lawful for proponents of non-designated projects unless the federal executive determines that the intra-provincial designated project is in the public interest.
5. The *IAA* mandates the federal executive to consider all effects of an intra-provincial designated project in determining whether the project is in the public interest even where those effects are not all linked, or sufficiently linked, to a federal head of power.
6. The *IAA* mandates the federal executive to consider all effects of an intra-provincial designated project in determining whether the project is in the public interest even where those effects include incidental effects of provincial laws on a federal head of power.
7. The *IAA* permits the federal executive to determine that an intra-provincial designated project is not in the public interest even where the adverse federal effects caused by that project are not material.
8. The *IAA* mandates the federal executive to take into account mandatory factors in determining whether an intra-provincial designated project is in the public interest, not all of which are linked to a federal head of power.
9. The public interest determination necessarily includes assessing whether the intra-provincial designated project overall is in the public interest – having regard to federal priorities and policies.
10. A negative public interest determination by the federal executive constitutes an effective veto of the intra-provincial designated project: the proponent is prohibited from proceeding even if the project satisfies, can satisfy, or does not otherwise require, any federal permit under other valid and applicable federal legislation.
11. The *IAA* authorizes the federal executive to impose on an intra-provincial designated project whatever conditions it chooses in relation to self-defined adverse "effects within federal jurisdiction" as part of the decision statement authorizing the project to proceed even though the adverse federal effects are not all within federal jurisdiction.
12. The *IAA* permits the federal executive to second guess and veto the results of a province's duty to consult under s 35 of the *Constitution Act*, 1982 with respect to an intra-provincial designated project where that duty arises.
13. The *IAA* authorizes the federal executive to stop an intra-provincial designated project even where agreements have been made by an Indigenous entity with either or both the provincial government and project proponent and with provincial approval.

Classification of the Subject Matter of the *IAA*

The ABCA found that the subject matter of the *IAA*, when applied to intra-provincial designated projects, falls within several heads of provincial power. Despite the blending of federal points of interest with the parts of the *IAA*, the *IAA* constitutes an invasion into provincial legislative jurisdiction and provincial proprietary rights. Parliament's claimed power to regulate all environmental and other effects of intra-provincial designated projects improperly intrudes into industrial activity, resource development, local works and undertakings, and other matters within provincial jurisdiction.

Greckol J.A. (Dissenting)

In the dissenting opinion, the Honourable Greckol J.A. found that, in enacting the *IAA* and *Regulation*, Parliament established a federal environmental assessment regime designed to regulate effects within federal jurisdiction. The Honourable Greckol J.A. found that the *IAA* confines its reach to the protection of the environment and the health, social and economic conditions within Parliament's legislative authority from the adverse environmental effects of select activities that in its view, have the greatest potential for adverse effects on areas of federal jurisdiction. The legislative regime prescribed in the *IAA* and *Regulations* is therefore a valid exercise of Parliament's authority and compliant with the *Constitution Act, 1867*, as amended.

***WCSB Alberta Limited Partnership v Alberta Utilities Commission,* 2022 ABCA 177**

Permission to Appeal - Law

In this decision, the Alberta Court of Appeal ("ABCA") considered three related applications for permission to appeal decisions by the AUC under s. 29 of the *Alberta Utilities Commission Act* ("*AUCA*"). Kalina Distributed Power Limited, Lionstooth Energy Inc., Signalta Resources Limited, and Campus Energy Partners (collectively, "KLSC") filed two applications requesting permission to appeal AUC Decision 26090-D01-2021("*Distribution-Connected Generation* ("DCG") *Credit Decision*) and AUC Decision 26660-D01-2021 ("*Review and Variance Decision*"). The ABCA approved KLSC's application for permission to appeal the *DCG Credit Decision*. WCSB Power Alberta Limited Partnership ("WCSB") also applied for permission to appeal the *DCG Credit Decision*. The ABCA dismissed WCSB's application.

<u>Background</u>

DCG credits have been part of the distribution tariff for at least some electrical distribution utilities for around 20 years. DCG credits relate to cost-savings resulting from DCG which distribution utilities flow through to Distribution-Connected Generators by those distribution utilities. The *DCG Credit Decision* phases out DCG credits over a five-year term.

The AUC's role is to determine tariffs under Division 2 of the *Electric Utilities Act* ("*EUA*"), whereby distributors may recover their prudent costs of operation plus a reasonable return on their capital investment. Under s. 121(2)(a) and (b) of the *EUA*, the AUC must ensure that (a) the "tariff is just and reasonable" and (b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of the *EUA*, other enactments, or any law.

The ABCA noted that different pieces of legislation forming part of a complex regulatory and service scheme should be read harmoniously so that they all work as intended.

<u>KLSC Applications</u>

DCG Credit Decision

In the *DCG Credit Decision,* the AUC explained that it had found itself addressing this policy topic in a FortisAlberta Inc. ("Fortis") tariff proceeding because an earlier Distribution System Inquiry had explored the issue of DCG credits, and the issue of those had also arisen in two earlier regulatory proceedings, but the circumstances there did not provide an appropriate means for a sufficient assessment. In consequence, the AUC separated this module from the Fortis tariff proceeding and issued a notice which said, amongst other things:

> … the Commission expects that its determinations in this proceeding (the DCG Credit Module for Fortis's 2022 Phase II distribution tariff application) will affect ATCO Electric, ENMAX, and Fortis, as well as their customers, and the owners and operators of DCG units that receive benefit from DCG credit mechanisms set out in each of those utilities' distribution tariffs.

KLSC submitted that use of the word "benefit" in this letter was a mischaracterization of the position of DCGs. KLSC said this set the process of this Fortis module on the wrong track. KLSC also submits that the letter, dated November 17, 2020, went on to state that it expected parties to provide evidence as to the following questions:

> (i) Should the Commission continue to approve the existing DCG credit mechanism in Fortis, ATCO Electric and ENMAX's respective distribution tariffs?

> (ii) Should consideration be given to adjusting the existing DCG credit mechanism? If so, based on what criteria and for what purpose?

The *DCG Credit Decision*, in the end, covered four questions, including the above two and two more:

> (iii) If these credits are to be retained as presently constituted or in an alternative form, comment on level-playing field considerations between DCG and transmission connected generation.
>
> (iv) If DCG credits are adjusted or eliminated, what issues should be examined, including the scope and timing of any adjustments?

KLSC submitted that Question (iv) arose in a mid-proceeding letter and that in context this was part of an unfair process that had been geared to a pre-determined outcome to dispose of the DCG credits. KLSC further pointed out that the AUC decided to take into consideration evidence and materials that it selected from the earlier Inquiry Proceeding, notably two Information Request responses (out of many) after the parties had filed their evidence. KLSC submitted that these steps were part of an unfolding of a process towards a pre-determined outcome.

KLSC further submitted that Question (iii) was not a proper topic for the Fortis proceeding, because the Fortis proceeding was explained by the AUC as being connected to s 121(2)(a) of the *EUA*, referring to whether the Fortis tariff would be "just and reasonable". KLSC says that although the AUC makes one reference to s 121(2)(b) in Decision 26090, none of its discussion really links its final decision to whether the inclusion of the DCG credits results in a tariff that was "unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of" the *EUA*, other enactments or law within the scope of s 121(2)(b). Relatedly, KLSC submits that reasoning about a "level playing field" as mentioned in Question (iii) and about interference with "efficient market outcomes" and causes "distortions" was outside the conceptual framework of "just and reasonable" and introduced policy considerations that KLSC was in no position to address.

KLSC also complains that despite reference to s 121(2)(a), the AUC declined to assign a burden of proof to Fortis under *EUA*, s 121(4) respecting the Option M element of its tariff.

Review and Variance Decision

KLSC launched its second application for permission, setting out a series of points, which the ABCA found would distill down to claims of reasonable apprehension of bias based upon the "*nemo judex*" principle and particularly pointing to the involvement of Mr. Larder as a member of both the *DCG Credit Decision* panel and the AUC Review Panel.

The ABCA found that the requirement of impartiality is expressed in part by the *nemo judex in sua causa* rule. But the ABCA further found that, that rule, when translated and applied means that no one should be a judge in his own case which, seen one way, would cover judges dealing with matters in which they have a personal interest. The ABCA interpreted KLSC's point to be that the *nemo judex* rule also means no decider should sit on a panel in appeal or review of a decision in which the decider participated. The ABCA found that while as a matter of apparent justice and of caution, it might be wise for a specific member not to participate in a review, there is no prohibition against such a member participating in a review.

Permission Decision

The ABCA granted the application from KLSC for permission to appeal on the following grounds:

1. The AUC erred in law in concluding that no party in proceeding 26090 had to assume the onus of proof with respect to whether the Distribution Utilities' DCG Credit tariff provisions were just and reasonable. Although the AUC suggested in Decision 26090 that it determined the facts at large without a burden on anyone, its reasons revealed that it placed a practical/evidential burden on the KLSC parties to prove a quantifiable benefit to ratepayers when KLSC was not in the position of such as FortisAB to meet such a burden.

2. The AUC erred in law when it considered larger policy issues such as a level playing field involving features of alleged market distortion and negatives for "efficient market outcomes" in its application of s 121(2)(a) of the *EUA*. Relatedly, the AUC erred in law when it directed the parties to provide submissions and evidence with respect to such larger policy considerations and when it extended itself into consideration of imported evidential materials from prior AUC proceedings and deployed them adversely to the position of KLSC.
3. The AUC failed to give procedural and adjudicative fairness and comply with the principles of natural justice in various manners, including the foregoing. It will be open to KLSC to discuss the process from the notice letter, dated November 17, 2020, up to and including the AUC decision as to remedy.

<u>WCSB Application</u>

The ABCA dismissed the application for permission to appeal the *DCG Credit Decision* filed by WCSB. WCSB was not a party in the AUC proceeding but submitted that it had a real stake or genuine interest in the outcome of an appeal of the *DCG Credit Decision*. However, it did not suggest that it has a public interest standing.

The ABCA determined that arguments proposed by WCSB only pick up those already suggested by KLSC. WCSB did not show that it could usefully add anything to the proceeding, as the AUC already granted KLSC permission to appeal.

The ABCA found that WCSB did not add anything crucial to the arguments of KLSC and that WCSB's arguments that go beyond KLSC's arguments were not advanced before the AUC or amounted to a collateral attack. WCSB's application for permission to appeal the *DCG Credit Decision* was therefore dismissed.

ALBERTA ENERGY REGULATOR

***Surety Bonds Oil Sands and Coal Mining Reclamation Security,* AER Bulletin 2022-017**
Coal - Mine Financial Security Program

Starting with the 2022 Mine Financial Security Program ("MFSP") annual report submissions, the AER will accept surety bonds as security under the MFSP program, along with cash and letters of credit, subject to the following conditions:

- The only acceptable form of surety bond is the AER-approved demand forfeiture bond, available on the AER's website. The AER will only accept demand forfeiture bonds without alterations.
- The AER will only accept surety providers with active operations in Canada.
- Only surety providers with at least an A− rating (or equivalent) from at least two public credit rating agencies of the AER's choosing will be accepted.

Manual 024: Guide to the Mine Financial Security Program has been updated to reflect this change.

***Invitation for Feedback on Revisions to Directive 065,* AER Bulletin 2022-018**
Oil and Gas - Law

The AER issued Bulletin 2022-018 seeking feedback on the proposed updates to *Directive 065: Applications for Oil and Gas Reservoirs*. *Directive 065.*

The proposed changes aim to clarify the application requirements for CO_2 enhanced oil recovery storage and CO_2 sequestration schemes, also known as carbon capture, utilization, and storage schemes. By clarifying the requirements, the goal is to increase transparency for industry and stakeholders and improve regulatory application efficiency and consistency.

The AER noted that the following directives will also be updated in the future:

- Directive 013: *Suspension Requirements for Wells*;
- Directive 020*: Well Abandonment*;
- Directive 051: *Injection and Disposal Wells — Well Classifications, Completions, Logging, and Testing Requirements*;
- Directive 056: *Energy Development Applications and Schedules (We will be updating participant involvement requirements to ensure sufficient notification radii for facilities and pipelines that handle CO_2 and for CO_2 injection wells.)*;
- Directive 071: *Emergency Preparedness and Response Requirements for the Petroleum Industry*; and
- Directive 087: *Well Integrity Management*.

ALBERTA UTILITIES COMMISSION

Proceeding and Roundtable to Establish Parameters for the Third Generation of Performance-Based Regulation Plans, AUC Bulletin 2022-06

Rates - Performance-Based Regulation

The AUC announced that it will initiate Proceeding 27388 to establish the parameters of the performance-based regulation ("PBR") plans that will start in 2024 ("PBR3") for Alberta distribution facility owners ("DFOs"). The PBR plans apply to ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and to two natural gas DFOs: ATCO Gas and Pipelines Ltd. and Apex Utilities Inc. To aid in establishing the scope of the proceeding, the AUC scheduled a roundtable with interested parties in September 2022.

In Decision 26356-D01-2021, the AUC evaluated the performance of the 2013-2017 and 2018-2022 terms of PBR and found that, on balance, PBR has achieved many of the objectives set out in the founding principles established by the AUC. The AUC determined that a third PBR term commencing in 2024, following a one-year cost-of-service rebasing year in 2023, is in the public interest if it incorporates certain improvements discussed in this bulletin.

The AUC indicated that it wishes to build on the information obtained in the evaluation of PBR proceeding that resulted in Decision 26356-D01-2021. In that decision, the AUC generally agreed with parties that PBR3 should be more reflective of ongoing economic conditions (for both the utilities and their customers) and ensure the cost efficiencies gained through PBR are shared amongst customers and the regulated companies. The AUC also expressed interest in making PBR3 simpler as compared to the previous plans in furtherance of the principle that a PBR plan should be easy to understand, implement and administer, with the overall aim of reducing regulatory burden over time.

The AUC highlighted the need to review the following parameters to determine if modifications are necessary:

- Any capital funding provisions, including the need for funding to keep pace with new trends affecting the grid.
- Ensuring that the inflation measure ("I factor") reflects the inflationary pressures expected during the PBR term.
- Consideration of the need to update a productivity offset ("X factor").
- Consideration of introducing a mechanism to share earnings.

The AUC also intends to examine whether it should continue to regulate gas and electric DFOs under two different PBR plans or whether they can be regulated under the same type of PBR plan.

Stakeholder Consultation on Design Standards for Electric Utility Connections for Greenfield Residential Developments and Associated Maximum Investment Levels for 2023, AUC Bulletin 2022-07

Electricity - Rates

Since the initiation of the consultation by Bulletin 2022-03 in March of 2022, AUC staff have met with stakeholders from individual organizations, including land developers and home builders, municipalities, electric distribution wire owners, and consumer groups to get insight on the issues associated with design standards that should be applicable for new home and residential electric utility connections and the associated maximum investment levels ("MILs"). An initial stakeholder meeting was held on Wednesday, April 27, 2022, to present the results of the discussions.

<u>Scope of the Consultations</u>

The AUC scheduled two working group meetings to discuss the following:

- Conduit usage requirements and potential MIL treatment; and

- Amperage requirements and potential MIL treatment.

The AUC noted that it might schedule follow-up working group sessions. The purpose and the expected outcome of these consultations will be to review the adequacy of current MILs provided by the electric distribution wire owners for 2023 to new single-family home greenfield developments. Future years' MILs will not be addressed in this phase of the consultation.

Any changes to MILs will be incorporated into the distribution utilities' 2023 rates either as part of the distribution utilities' ongoing cost-of-service rebasing application compliance filings or through an alternative process established by the AUC.

<u>Cost Recovery</u>

The AUC noted that the only stakeholder eligible for cost recovery for participating in the consultation would be the Consumer's Coalition of Alberta ("CCA"), as the representative of two consumer groups, the Consumers' Association of Canada (Alberta Division) and the Alberta Council on Aging. The AUC requested that the CCA coordinates with the Utilities Consumer Advocate on common matters to avoid duplication of effort, resources, evidence, and costs. The AUC will assess any cost claims under the relevant principles set out in AUC Rule 022: *Rules on Costs in Utility Rate Proceedings* and the scale of costs associated with that rule.

The CCA was directed to file a costs claim with the AUC within 30 days of the close of the consultation process and include in its application a proposal for recovery of its costs.

***Alberta Electric System Operator Application for Approval of the Adjusted Metering Practice Implementation Plan and Associated Section 502.10 of the ISO Rules*, AUC Decision 27047-D01-2022**
ISO Rules

In this decision, the AUC refused an application by the Alberta Electric System Operator ("AESO") for approval of the adjusted metering practice ("AMP") implementation plan. The AUC considered whether the AMP implementation plan and the related proposed amendments to the Independent System Operator ("ISO") tariff and s. 502.10 of the ISO Rules, *Revenue Metering System Technical and Operating Requirements,* provided a way to implement the AMP that complies with the *Electric Utilities Act* ("*EUA*").

<u>Background and Application</u>

In Decision 22942-D02-2019, the AUC approved the 2018 ISO tariff, including the AESO's proposed AMP. In Decision 25848-D01-20220, the AUC varied its findings from Decision 22942 and determined that grandfathering the AMP was unnecessary.

The AESO filed this application in compliance with directions issued in Decision 26215-D02-2021.

<u>Issues</u>

Do the Rule Amendments Meet the Criteria set out in the EUA

The AUC found that the AESO's proposed amendments to the ISO Rules are consistent with the statutory scheme and authorized by subsections 20(1)(a), 20(1)(c), and 20(1)(l) of the *EUA*. The AUC further found that the rules, as amended, are complete and reasonably self-contained. The AUC was therefore satisfied that the proposed amendments do not render the rules technically deficient. The AUC was also satisfied that the AESO had complied with requirements regarding information and consultation set out in Rule 017.

The AUC was not satisfied that the proposed amendments support the fair, efficient and openly competitive operation of the electricity market or that the proposed amendment is in the public interest. The AUC noted that the phase-out of distribution-connected generator ("DCG") credits will substantially decrease billing determinant erosion, independent of the implementation of the AMP. It was therefore not clear how much benefit the AMP implementation would provide.

As a result, the AUC could not evaluate the AESO's claim that the benefits of more accurate billing determinants provide sufficient justification for the different timing of implementation at Category B and Category C substations.

The AUC was not satisfied with the accuracy and available information related to the cost estimates provided by the AESO in the AMP implementation plan. The AUC was concerned that it could not conduct a reasonable assessment of the AESO's Phase 3 costs estimates. With no information on the estimated costs of Phase 3, and given that the requested approval of the AMP implementation plan includes Phase 3, the AUC must be satisfied that Phase 3 costs are (1) reasonable and (2) in the public interest. The AESO did not provide sufficient cost estimates to allow for this assessment.

As a result, the AUC determined that the AESO did not demonstrate that the submitted AMP implementation plan would be in the public interest.

Given this uncertainty, the AUC did not require the AESO to file a further application proposing an implementation plan for the AMP. However, if the AESO does wish to apply for approval of an AMP implementation plan in the future, the AUC sets out specific information requirements in this decision.

Order

The AUC noted that s. 20.21(4) of the *EUA* sets out that the AESO must satisfy the AUC that the approval criteria are met. The application from the AESO did not discharge this onus.

Accordingly, pursuant to subsection 20.21(1)(c) of the *EUA*, the AUC denied the application.

***AltaLink Management Ltd. Decision on Application for Review and Variance of Decision 26509-D01-2022 (Corrigenda) AltaLink Management Ltd. 2022-2023 General Tariff Application,* AUC Decision 27246-D01-2022**

Tariff - Rates

In this decision, the AUC denied the application from AltaLink Management Ltd. ("AML") for review and variance of Decision 26509-D01-2022 (Corrigenda). AML requested that the AUC review and vary its findings to allow AML to refund $120 million of surplus accumulated depreciation to the Alberta Electric System Operator (the "Tariff Refund"). The AUC denied the application as the request, and the proposal to credit the amount to Alberta's electricity customers to reduce their electricity bills from July to September 2022 would not result in a just and reasonable tariff.

AML's proposal would result in an average Alberta residential customer receiving a bill reduction of $5 per month in July, August, and September 2022. After that, their electricity bills would be higher for the next 46 years than would otherwise be the case. The AUC characterized AML's proposal as a loan rather than a refund since refunds do not have to be paid back by the person that receives them. Unlike a refund, Alberta's electricity customers will have to return the $120 million plus carrying charges to AML. It is currently expected that Alberta electricity customers would pay AML back $251.6 million through increased electricity rates, including approximately $85 million in expected profit to AML 's owners.

The AUC's Review Process

Typically, the AUC review process has two stages. In the first stage, a review panel decides if there are grounds to review the original decision (the "Preliminary Question"). If a review panel decides to review the decision, it moves to the second stage where it decides whether to confirm, vary, or rescind the original decision (the "Variance Question"). In this proceeding, the review panel decided on the Preliminary Question and the Variance Question in one proceeding pursuant to Section 6(2) of Rule 016.

Timing of the Review Application

AML applied for review and variance outside the 30-day deadline set out in Rule 016: *Review of Commission Decisions*. AML relied on events that occurred or continued to occur after the 30-day deadline, and the AUC exercised its discretion under s. 3(3) of Rule 016 to consider the application.

Decision on the Preliminary Question

To support its review application, AML submitted that the economic conditions that existed when Decision 26509-D01-2022 (Corrigenda) was issued, no longer apply. AML cited, among other things, the ongoing invasion of Ukraine and the recent rise in oil and gas commodity prices and resulting increases in energy costs for Albertans. AML also referred to the tight electricity supply market and upward pressure on electricity prices for Albertans, and increasing levels of inflation and increasing interest rates as constituting materially changed circumstances.

The review panel was satisfied that the recent economic and geopolitical developments outlined by AML amount to changed circumstances material to Decision 26509-D01-2022 and allowed the review application on this basis.

Decision on the Variance Question

The review panel found that AML's proposal does not result in a just and reasonable tariff and denied AML's request to refund $120 million in accumulated depreciation in 2022 for the following reasons:

(a) The long-term costs of AML's refund proposal outweigh the short-term benefits. This was a concern that was also noted by the Consumers' Coalition of Alberta. AMLs current proposal to refund $120 million of accumulated depreciation in 2022 provides AML with an estimated additional $251.6 million in revenue requirement over the years 2022-2067.

(b) AML's proposal to refund $120 million of accumulated depreciation in 2022 provides an average residential customer approximately $5 per month of rate relief for each of July, August, and September 2022. The review panel does not agree with AML that this amounts to "significant additional support" to average residential customers, particularly in view of the burden that would be imposed on them in the future.

(c) A small percentage of the refund would be allocated to residential customers and small commercial customers. In particular, approximately $19 million (or roughly 16 per cent) of the total $120 million refund would flow through to customers identified as residential and approximately $12 million (or roughly 10 per cent) would flow through to small commercial customers. These allocations contradict AML's stated reasons for the refund, which focused on the financial hardship facing residential and small commercial customers.

(d) Industrial Power Consumers Association of Alberta, a representative of large industrial customers, stated that it was "prepared to accept the AUC's original Decision on this matter and move on to initiatives that can help save customer dollars in the long-term."

(e) AML's analysis that shows a benefit to Alberta electricity customers resulting from its proposal is incomplete and flawed. AML relies on a 20 per cent interest rate, based on credit card debt, to show a net benefit of $80 million to all Alberta's customers over 46 years resulting from its proposal. There is no evidence on the record that demonstrates a substantial majority of Alberta electricity customers are facing debt rates of 20 per cent, or that credit card interest rates apply to the larger consumers of electricity who would receive the majority of AML's refund.

(f) The review panel rejected the assertions of AML and Patrick Bowman (on behalf of the Office of the Utilities Consumer Advocate) that an immediate refund in 2022 results in a just and reasonable tariff to past, present, and future customers. The review panel found that the refund would not be fair to future customers. There is no persuasive reason why future customers should pay higher electricity rates for 46 years given the modest relief in 2022.

(g) As applied for, AML's refund proposal (in the current review & variance application) increases its revenue requirement by an additional $3.4 million in the years 2022-2023 compared to its previous refund proposal. This incremental benefit to AML is inconsistent with AML's statement that the refund is "overwhelmingly in the public interest."

(h) AML's portrayal of Alberta's economic circumstances ignores the province's recovery from the COVID-19 pandemic and the economic growth experienced in Alberta over the first three months of 2022, which is expected to continue. The review panel disagreed with AML's argument that Alberta's economy has materially deteriorated since the time of AML's application update in early September 2021, or from the issuing of Decision 26509-D01-2022 (Corrigenda) on January 19, 2022.

AUC Decision

The AUC found that AML's proposal would not result in a just and reasonable tariff. While it would provide Alberta's current electricity customers with modest relief on their electricity bills, the proposal would immediately require Alberta's electricity customers to pay back its "refund" with interest and other carrying charges over the next 46 years. Accordingly, the AUC denied AML's request to vary the original decision.

***Direct Energy Regulated Services Default Rate Tariff and Regulated Rate Tariff Application for Interim Rates True-Up and 2021 Bad Debt and Late Payment Charge Deferral Account Disposition,* AUC Decision 27273-D01-2022**

Rates - Energy

In this decision, the AUC approved the application from Direct Energy Regulated Services ("DERS") to true-up its interim rates for the default rate tariff ("DRT") and the regulated rate tariff ("RRT") and to dispose of the balance in the 2021 bad debt and late payment charge deferral account.

The AUC determined the true-up amounts provided in this decision and amounts to be included in the monthly gas cost flow-through rate ("GCFR"), effective June 1, 2022, until November 30, 2022.

Interim Rates True-up Amounts

DERS requested approval of the rate true-up regarding five rates and charges. For this true-up of interim rates, DERS calculated the difference between the revenues it would have had if final rates had been in place for the interim rate period and the actual revenues for the same period using the approved interim rates in place. The AUC was satisfied that DERS calculated the true-up amounts correctly and approved the following amounts to be collected from customers from January 1, 2020, to June 30, 2021.

Service Charges	True-up Amount to be Collected ($000)
RRT Non-Energy Total (Including seven rate classes)	2,651.2
DRT Non-Energy Total (including three rate classes)	3,001.2
DRT Return Margin	262.6
DRT Certain Energy Costs	2,314.5
DRT Labour Costs Related to Gas Procurement	3.8

2021 Bad Debt and Late Payment Charge Deferral Account Balances

DERS' 2020-2022 DRT and RRT revenue requirements and rates were determined through negotiations with customer groups. The negotiated settlement agreement ("NSA") was approved by the AUC in Decision 26207-D01-2021.

The NSA included provisions regarding the bad debt and late payment charge components of the revenue requirement for 2020-2022. The net balance in the DRT bad debt and late payment charge deferral account must be separated between the energy balance and the non-energy balance, and the non-energy balance is then separated between the three rate classes. DERS calculated the energy and non-energy balances using the energy and non-energy forecast allocation percentages from the NSA. The non-energy balance for each rate class was also calculated using the forecast number of bills allocation percentages from the NSA. The AUC requested DERS to recalculate the energy and non-energy balances and the non-energy balances by rate class using actual information as opposed to the forecasts. The AUC approved the energy and non-energy balances by rate class of the 2021 DRT net bad debt and late payment charge deferral account balance as recalculated.

The net balance in the RRT bad debt and late payment charge deferral account must be separated between the seven rate classes. In the application, DERS calculated the balance for each rate class using the forecast number of bills allocation percentages from the NSA. The AUC requested DERS to recalculate the balances by rate class using the NSA methodology and actual information. The AUC approved the balances by rate class of the 2021 RRT net bad debt and late payment charge deferral account balance.

Proposal to Collect or Refund as Applicable the Combined Interim Rates True-up Amounts and Net Bad Debt and Late Payment Charge Deferral Account Balances

DERS proposed to collect the RRT and DRT non-energy totals from customers through the addition of a rate rider over the period from June 1, 2022, to November 30, 2022. DERS also proposed to collect the DRT energy total before labour costs related to the procurement during the same period as part of the GCFR.

The AUC approved the proposal to combine the interim rates true-up amounts and the net bad debt and late payment charge deferral account balances. The AUC also approved DERS' proposal to collect or refund, as applicable, the combined balances over a six-month time period because it results in average monthly bill increases of less than 2 percent for residential DRT and RRT customers.

Proposal to File an Application to Provide Actual Rider Revenue and Forecast Rider Revenue

DERS noted that it calculated the rate riders approved in this application using a six-month forecast for site counts. The amounts collected or refunded through the rate riders will likely differ from the combined balances. DERS proposed to submit an application by no later than January 31, 2023, that would include the actual amounts collected or refunded, the approved combined balances, and the resulting differences.

The AUC approved the application and directed DERS to file an application, including the actual RRT and DRT non-energy rider revenues and refunds by rate class, the corresponding approved non-energy combined balances, the resulting differences, and, if needed, a true-up proposal, by no later than January 31, 2023.

Order

The AUC approved DERS' DRT for non-energy true-up riders. The AUC also approved the monthly amounts totaling $1,767,762 for DRT energy and non-energy costs and RRT non-energy to be included in the respective monthly GCFR filings for June 2022 to November 2022.

***Direct Energy Regulated Services Amended 2020-2022 Energy Price Setting Plan (Index)*, AUC Decision 27262-D01-2022**

Rates - Electricity

In this decision, the AUC approved Direct Energy Regulated Services ("DERS") amended 2020-2022 energy price setting plan ("EPSP") Index.

After the AUC approved the negotiated settlement agreement ("NSA") for DERS' 2020-2022 EPSP, DERS requested approval of changes to the EPSP Index that would account for updated pricing and procurement information using additional market data. The amendments relate to the indexing coefficients in the index methodology of the EPSP Index used to calculate the monthly energy charge for electricity.

DERS' Amendments to the Indexing Coefficients in the Indexing Methodology

As agreed to in the AUC-approved NSA, DERS applied for approval of amendments to the EPSP Index to incorporate updated coefficients, as updated load data was causing a material change to the indexing coefficients. In its application, DERS provided settlement data from September 1, 2021, to February 28, 2022, which was not included in the original application and was used to update the indexing coefficient for the summer months and the indexing coefficient for the winter months.

DERS submitted its application to update the indexing coefficients of its 2020-2022 EPSP Index "to reflect that a consistent sample period should be used to estimate each seasonal multiplier".

The AUC determined that the amendments are needed to ensure a reasonable opportunity for DERS to recover its prudent costs and expenses. The AUC also determined that DERS' use of the updated data would better align periods for recovering costs and expenses by incorporating more recent load settlement data. This achieves a more accurate rate design and certainty.

The AUC, therefore, approved the 2020-2022 EPSP Index amendments to account for updated load settlement data.

Compliance with Previous AUC Directions

The AUC found that DERS complied with the directions issued in Decision 25818-D01-2021. DERS was required, under the approved NSA, to provide further information.

DERS met its obligation to provide data regarding:

(a) Hourly settlement volumes for DERS and EPCOR Energy Alberta GP Inc. ("EPCOR") and Hourly Alberta Pool prices from the Alberta Electric System Operator;

(b) EPCOR's "Average Full-Load Price", "Average Flat Price", and "Average Price" from the EPCOR monthly regulate rate tariff ("RRT") Energy Charge Calculation;

(c) DERS' flat, peak, and procurement-volume-weighted block procurement prices from DERS' Final RRT Monthly Rates; and

(d) DERS' derived commodity risk compensation from DERS' Final RRT Monthly Rates.

The AUC found that DERS was not required to file further information, as it had either already been provided or was otherwise available.

AUC Decision

The AUC approved DERS' amended 2020-2022 EPSP Index effective June 1, 2022.

Enel Alberta Wind Inc. Grizzly Bear Creek Wind Power Project, **AUC Decision 26677-D01-2022**
Wind Power - Facilities

In this decision, the AUC approved the application from Enel Alberta Wind Inc. ("Enel") to construct and operate the 152.1-megawatt ("MW") power plant designated as the Grizzly Bear Creek Wind Power Plant (the "Power Plant"). The AUC also approved the application to construct the Grizzly Bear Creek Wind Power Project 708S Substation (collectively, the "Project").

Applications

Enel applied for approval to amend the previously approved Project, located on 18,566 acres near the town of Mannville, Alberta. The Project will consist of 31 4.5-MW Vestas V150 turbines with a hub height of 120 meters, a rotor diameter of 150 meters, and an overall blade tip height of 193.7 meters, and three 4.2-MW Vestas V136 turbines with a hub height of 82 meters, a rotor diameter of 136 meters and an overall blade tip height of 148.7 meters. The Project was previously owned by E.ON Climate & Renewables Canada Inc. ("E.ON") and was approved by the AUC in 2016. At the time, the project consisted of 50 wind turbine generators with an individual generation capacity of 2.4 megawatts (MW). Enel acquired the project from E.ON in May 2019 and was authorized to construct and operate the Project pursuant to Power Plant Approval 26612-D02-2021 and Substation Permit and Licence 26612-D03-2021.

Even though the original project approvals were still valid, the AUC decided to treat the amendment applications as a new project since Enel advised that it is unable to construct its previously approved project, as the necessary turbine model is no longer commercially available. In addition, the applied-for project was substantially re-designed by increasing the capacity from 120 MW to 154 MW and relocating a large portion of the project infrastructure, including the associated substation. As a result, the proposed amendments have the potential to result in different environmental, visual, and construction impacts than were previously considered by the AUC, including the evolving regulatory standards since 2016.

The AUC approved Enel's application to construct and operate the Grizzly Bear Creek Wind Power Plant and issued Approval 26677-D02-2022, pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*. The AUC also approved Enel's application to construct and operate the Grizzly Bear Creek Wind Power Project 708S Substation, issuing Permit and Licence 26677-D03-2022, pursuant to sections 14, 15, and 19 of the *Hydro and Electric Energy Act*.

Finally, the AUC rescinded Power Plant Approval 26612-D02-2021 and Substation Permit and Licence 26612-D03-2021, which approved the original project in 2016.

AUC Discussion and Findings

The AUC issued a notice of application in accordance with Rule 001: *Rules of Practice.* The Grizzly Landowner Group ("GLG") issued a statement of intent to participate, indicating their opposition to the Project. The AUC granted standing to the GLG. The GLG requested that the AUC deny the applications. In the alternative, the GLG recommended several conditions should the AUC decide to approve the project.

In granting the applications, the AUC considered the following issues:

Noise Impacts

The GLG raised several concerns regarding noise impacts and questioned the Project's compliance with Rule 012: *Noise Control*. GLG requested that the AUC require Enel to update its noise impact assessment ("NIA") to include the most up-to-date Project design.

To determine if the NIA meets the requirements of Rule 012, the AUC considered concerns about the accuracy or conservatism of the noise modelling, potential additional receptors, and adequacy of baseline case modelling.

With respect to the conservatism of the noise modelling for the project, the AUC found that the several conservative assumptions incorporated in the NIA sufficiently compensated for the level of uncertainty inherent in the noise model developed for the project. Consequently, there was no need to require Enel to incorporate additional uncertainty factors into the project NIA. The AUC determined that the NIA met the requirements of Rule 012.

The AUC found that it was unnecessary for Enel to proactively provide sound source ranking tables for the most affected receptors in preparation for potential future noise mitigation measures. As a condition of approval, the AUC required that Enel conducts a post-construction comprehensive sound level ("CSL") survey, including an evaluation of low-frequency noise, at receptors R1, R8, and R55, in accordance with Rule 012. Enel was directed to file a report of this survey with the AUC within one year of the Project's start of operation.

In relation to infrasound, the AUC found that measuring infrasound from turbines would not likely provide helpful information to assess project compliance with Rule 012, and it did not require Enel to measure infrasound as part of the CSL survey.

As a result, the AUC found that the project NIA and associated noise model met the requirements of Rule 012, that the Project is expected to be compliant with Rule 012 at all receptors, and that Enel will generally adhere to mitigation measures for construction noise set out in Rule 012.

Visual Impacts Including Shadow Flicker

The GLG raised concerns about the visual impacts of the project, such as how the presence of turbines will affect the rural character of the Project area and the impacts of shadow flicker on nearby residences.

The AUC acknowledged that large wind projects alter the landscape and, that for the GLG, result in visually unattractive impacts. The AUC balanced this factor against the project's public benefits and concluded that the project's benefits outweigh any negative impacts making it in the public interest.

With regard to shadow flicker, the AUC was satisfied that the shadow flicker assessment met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. According to the AUC, the potential shadow flicker impacts of no more than 13 hours per year are minimal because they represent a small proportion of daylight hours within the year and fall below the 30-hour per year criteria commonly applied to wind projects.

The AUC directed Enel to file a report detailing any complaints or concerns it receives from local landowners regarding shadow flicker from the project during its first year of operation, as well as Enel's response to the complaints or concerns. The report must detail any implemented mitigation measures and associated stakeholders' feedback regarding the mitigation. Enel must file this report no later than 13 months after the project becomes operational.

Finally, the AUC found no persuasive evidence that the project, operating as proposed in the applications, is likely to result in adverse health effects for nearby residents as a result of noise, shadow flicker, or other impacts from the Project.

Agricultural Impacts

The GLG was concerned by the spread of clubroot and other soil-borne diseases due to soil transportation during the Project's construction. Enel submitted a clubroot management plan designed to address the concerns raised by the GLG. The AUC determined that Enel's proposed measures appropriately mitigate clubroot concerns.

The AUC also considered the impact of the Project on the landowners' ability to aerially spray crops. The AUC found that the loss of the ability to use aerial spraying due to the presence of turbines has a negative impact on the GLG because significant precipitation, urgent pest or disease pressure, or mature crops could necessitate immediate aerial spraying.

The AUC determined that the risk of economic loss due to the Project's impact on the option of aerial spraying is nevertheless low, as landowners rarely use aerial spraying, considering that high-clearance ground spraying has generally been effective.

Property Value Impacts

GLG members expressed concern with negative property value impacts from the Project, largely due to the visibility of the Project's turbines from their residences. The AUC stated that it preferred to assess property value impacts based on project-specific evidence provided by experts and tested or made available for testing in a hearing. The AUC also acknowledged that project-specific evidence may not always be readily available due to the absence of local sales data.

In this proceeding, both parties filed evidence on property value impacts, which evidence reviewed third-party case studies and reports from other jurisdictions addressing the impacts of wind farms on property values. The AUC gave little weight to the conclusion in these studies, as it was not satisfied that the studies were representative of rural Alberta and the Project area.

However, based on the report from the GLG and in the absence of reliable empirical data regarding property market impacts in evidence from Enel, the AUC determined that there was a negative perception of the Project's visual effects that may translate into a negative impact on property value between zero and 10 per cent.

Other Issues

The AUC considered issues regarding consultation, construction, reclamation, and environmental and wildlife impacts.

The AUC found that Enel's visual simulations provided a reasonable representation of the visual impact of the turbines and project layout and that the participant involvement program meets the requirements of Rule 007.

The AUC further determined that the required road use agreement with the counties and Enel's commitment to implement dust control measures reasonably address the GLG's concerns about construction dust and traffic impacts.

The AUC was of the view that Enel's reclamation responsibilities at the Project's end of life are adequately addressed by existing reclamation requirements, including Enel's lease agreements with Project host landowners and the applicable legislative regulations.

Enel submitted wetland and wildlife surveys that were developed and conducted according to Alberta Environment and Parks ("AEP") standards and protocols. The AUC was satisfied with the submitted reports and determined that further surveys requested by the GLG were unnecessary. Further, the AUC determined that Enel's commitments to mitigating measures reduce potential wetland and wildlife impacts to an acceptable level.

As a final condition of approval regarding environmental and wildlife impacts, the AUC required that Enel submit to AEP and the AUC annual post-construction monitoring survey reports regarding the Project, as required by Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*.

<u>Conclusion</u>

The AUC found that the benefits of the Project, including its ability to generate 152.1 MW of emissions-free electricity, the expected $80 million in local tax revenues, and the creation of temporary and full-time jobs, outweigh the potential negative impacts. The AUC determined the approval of the Project to be in the public interest.

Pursuant to s. 11 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the application to construct and operate the Power Plant. The AUC issued the permit and license to construct and operate the Substation pursuant to s. 14, 15, and 19 of the *Hydro and Electric Energy Act*. The Project is expected to be placed and in-service by November 25, 2022.

***Enforcement Staff of the AUC Allegations Against Green Block Mining Corp. Westlock Power Plant Phase 1,* AUC Decision 26379-D03-2022**
Enforcement - Contraventions

In this decision, the AUC determined that Green Block Mining Corp. ("Green Block"), formerly known as Link Global Technologies Inc., contravened the *Hydro and Electric Energy Act* ("*HEEA*") and Rule 007: *Applications for Power*

Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines when it began operating the Westlock Power Plant without AUC approval.

Background

AUC enforcement proceedings typically have two phases. In the first phase, enforcement staff have the burden of proving allegations set out in their enforcement application on a balance of probabilities. If an allegation in the first phase is proven, the proceeding moves to the second phase, where a penalty is determined.

Green Block began operating three power plants (its Sturgeon, Kirkwall, and Westlock power plants) in Alberta in 2019-2020 without obtaining approval from the AUC. A first phase (Phase 1) decision was previously issued in this proceeding, in which the AUC determined that Green Block operated its Sturgeon and Kirkwall power plants in contravention of the *HEEA* and Rule 007.

The AUC reopened Phase 1 of the Enforcement proceeding to re-examine the own-use issue in light of Green Block's new information. The AUC combined the reopened Phase proceeding with a new proceeding to consider new enforcement staff allegations relating to the Westlock Power Plant. The enforcement staff alleged that Green Block operated the Westlock Power Plant contrary to the *HEEA* and Rule 007 (“Contravention 1”). Enforcement staff also alleged that Green Block concealed its actions, impeding the AUC’s ability to effectively and efficiently regulate in the public interest (“Contravention 2”).

In a later ruling, the AUC accepted the proposal from the enforcement staff to withdraw the allegations regarding Contravention 2. As a result of the withdrawal, the only remaining issue was if Green Block operated the Westlock Power Plant contrary to the *HEEA*.

Did Green Block Operate the Westlock Power Plant Contrary to the *HEEA* and Rule 007?

The Westlock Power Plant is a facility comprised of six 1.475-megawatt gas generators in Westlock County, Alberta, which supply power to a set of computers used to mine bitcoins. Green Block began operating the Westlock Power Plant on March 10, 2021.

At the time of this alleged contravention, there was an exemption from the general requirement to obtain AUC approval of a Power Plant under s. 13 of the *HEEA* and Rule 007 in force. The exemption applied to power plants generating electric energy solely for a person’s own use provided the power plant met certain requirements to ensure that it was operated in regulatory compliance.

Green Block admitted that it did not ensure that the Westlock Power Plant complied with Rule 012: *Noise Control* before operating. Green Block also admitted that it did not ensure that the Westlock Power Plant would not have adverse environmental effects. Accordingly, Green Block failed to take any steps to ensure that the Westlock Power Plant was in regulatory compliance.

The AUC accepted the admissions and found that Green Block was in contravention of the *HEEA* and Rule 007. The AUC will consider sanctions in the second phase of this proceeding.

EPCOR Energy Alberta GP Inc. 2021-2022 Regulated Rate Tariff Refiling Application, AUC Decision 27305-D01-2022

Rates - Electricity

In this decision, the AUC approved the 2021-2022 regulated rate tariff (“RRT”) refiling application filed by EPCOR Energy Alberta GP Inc. (“EPCOR”). EPCOR requested approval of the refiled RRT non-energy revenue requirement, price schedules, authorization to collect or refund the variance between interim and final rates over a four-month period from August 1, 2022, to November 30, 2022, and approval of terms and conditions of service.

Background

In Decision 26694-D01-2022 (the "Decision"), the AUC approved a negotiated settlement agreement ("NSA") reached between EPCOR, the Consumers' Coalition of Alberta ("CCA"), and the Office of the Utilities Consumer Advocate ("UCA") for EPCOR's 2021-2022 non-energy RRT. EPCOR filed this refiling application in accordance with AUC directions issued in the Decision.

In the Decision, the AUC directed EPCOR to revise its COVID-19 deferral account to exclude specific COVID-19 amounts, reflect a credit of $130,000 to EPCOR's customers, and exclude credit costs of $690,000 and $700,000 from its 2021 and 2022 revenue requirements, respectively.

EPCOR updated its 2021 and 2022 revenue requirements to reflect the changed NSA adjustment amounts. EPCOR reduced its RRT allocated revenue requirement by $3.82 million and $2.2 million for 2021 and 2022, respectively. EPCOR also amended the NSA to correct errors related to customer relationship management costs, bad debt, and late payment charges. The result was a reduction of the 2021 and 2022 revenue requirements by $70,000 and $370,000, respectively.

EPCOR's correction of errors and omissions increased the 2021 revenue requirement by $572,000 and decreased the 2022 revenue requirement by $156,000.

Issues

Compliance with AUC Directions

The AUC was satisfied that EPCOR had adjusted its 2021 and 2022 revenue requirements regarding COVID-19-related deferral costs and forecast non-energy credit costs.

The AUC reviewed EPCOR's 2018 and 2019 true-up calculations for non-energy rates and was satisfied that EPCOR properly applied the final Alberta Electric System Operator ("AESO") settlement data to true-up the variance between interim and final rates. Although the AUC approved EPCOR's calculations for truing up the variance between interim and final rates from January 1, 2018, until June 30, 2019, in Decision 24034-D01-2019, the calculations were based on a mix of actual and forecasted sites. EPCOR proposed to true-up the difference in revenue between interim and final rates in the full 2018 calendar year to reflect final AESO settlement data for that period, and the difference in revenue collected from interim to final rates from January 1, 2019, to June 30, 2019, to reflect the final AESO settlement. However, given the immateriality of the true-up amounts and the fact that they will have no measurable impact on customers or EPCOR, the AUC decided that it was unnecessary to recover EPCOR's true-up of $1000 from customers for 2018 and $1000 from customers for the period January 1, 2019, to June 30, 2019. The AUC, therefore, denied the 2018 and 2019 true-up amounts.

Proposal for Interim and Final Rate True-up Adjustments

The AUC approved collecting true-up amounts through rate riders separated by customer group and service area. EPCOR's proposed riders for residential customers will result in decreases to customers' average monthly bills ranging from 0.09 to 0.79 percent. With the exception of increases for oil and gas customers in the FortisAlberta Inc. ("FortisAB") service area, the AUC was satisfied that decreases in this range do not indicate rate shock.

EPCOR submitted that despite the 17.54 percent increase in rates for FortisAB oil and gas customers, the impact is reasonable because it had allocated bad debt costs by customer class; the shock had been mitigated by spreading it over four months, and the impact is localized to a single customer class with a relatively small amount of customers.

The AUC accepted the explanation that there was a significant bad debt write-off for the FortisAB oil and gas customer in 2021, which significantly increased the updated forecast bad debt for this class. The proposed interim and final rate true-up adjustments were approved as filed.

Revenue Requirements and Price Schedules and Terms and Conditions of Service

The AUC was satisfied that EPCOR's revenue requirements and related price schedule were consistent with the terms of the NSA and the amended NSA provided in this refiling application. The price schedules for the FortisAB service area and the EPCOR Distribution & Transmission Inc. service area reflect the approved revenue requirement of $41.81 million and $38.76 million in 2021 and 2022, respectively.

The AUC approved proposed changes to EPCOR's terms and conditions of service, including changes to definitions regarding Rule 003, as they were minor.

AUC Decision

The AUC approved EPCOR's 2021 and 2022 revenue requirements, non-energy rates, and rate and price schedules as filed. The AUC also approved the terms and conditions of service.

Melcor Developments Ltd., Highview Communities Inc., and Sunset Properties Inc. Complaint Regarding FortisAlberta Inc. Changing Design Standards, **AUC Decision 26649-D02-2022**
Electricity - Discriminatory Service

This decision provided the reasons for the AUC's dismissal of the complaint filed by Melcor Developments Ltd., Highview Communities Inc., and Sunset Properties Inc. (the "Melcor Entities") in Decision 26649-D01-2022. The Melcor Entities filed a complaint relating to changing design standards and associated costs imposed by FortisAlberta Inc. ("FortisAB") to design and install underground electrical distribution systems for residential developments.

Introduction and Procedural Background

The Melcor Entities had entered into an agreement under which the Melcor Entities were responsible for managing the design, construction, and installation of electrical facilities within a subdivision's boundaries to certain minimum design standards mandated by FortisAB. Once the distribution system was completed and energized, FortisAB would take over ownership of the system. FortisAB would complete all work outside the subdivision's boundaries to provide electric service to the development.

As part of the process to initiate services for new developments, FortisAB requires residential developers to sign an Underground Electrical Distribution System ("UEDS") Services Agreement and a quotation letter and pay any required customer contribution.

On June 30, 2021, the Melcor Entities filed a complaint application with the AUC. The Melcor Entities requested relief from the AUC as issues had arisen concerning the construction of electrical distribution systems to service lands owned by the Melcor Entities in FortisAB's service area.

The Melcor Entities sought an order from the AUC declaring that their payments to FortisAB for the cost to install and construct electrical distribution facilities in three developments, namely, Lanark Landing, Phase 1C ("Lanark"); Sunset Ridge, Phase 22B ("Sunset"); and Cobblestone Creek, Phase 2, be interim and subject to adjustment based on the outcome of the complaint. The AUC granted interim relief in August 2021.

Issues and AUC Findings

The Melcor Entities submitted that FortisAB had breached its obligations under the *Electric Utilities Act* ("*EUA*") to provide distribution service that is not unduly discriminatory. The complaint alleged that the required design standards applicable to the subject developments identified in FortisAB's agreements and quotation letters were contrary to the *EUA.* In applying the standards, FortisAB was acting in a manner that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of law.

Were the Design Standards Imposed in a Manner Inconsistent with a Proper Application of the AUC-Approved T&Cs?

The investment levels for residential services are established in FortisAB's Customer Terms and Conditions of Electric Distribution Service ("T&Cs"), which the AUC approves.

The Melcor Entities acknowledged that the T&Cs do not deal with how FortisAB may implement changes to the minimum design standards for new service connections; however, they submitted that the T&Cs do address the maximum investment that Fortis will make in new service connections. The Melcor Entities acknowledged that the changes to FortisAB's maximum investment levels ("MILs") are outside the scope of the current proceeding. The Melcor Entities however argued that FortisAB's unilateral implementation of the standards for constructing new service connections upset the balance between what an individual customer pays upfront versus what all customers will pay through ongoing rates. The Melcor Entities argued that this was because FortisAB changed the standards, increasing the upfront costs to developers, before considering a change in investment policy. In the Melcor Entities' view, the standards were therefore imposed in a manner inconsistent with a proper application of the T&Cs.

The AUC was not persuaded that a change in design standards without a corresponding change in MILs is inconsistent with a proper application of the T&Cs. The Melcor Entities have failed to demonstrate that the T&Cs restrict, or otherwise limit, FortisAB's discretion with respect to the implementation of the design standards. The Melcor Entities further did not demonstrate that FortisAB was required to change its MILs concurrently with its design standards. Accordingly, the AUC found that the design standards applicable to the subject developments have not been imposed in a manner inconsistent with the proper application of the T&Cs.

Did the Design Standards Result in Unduly Discriminatory Electric Distribution Service and Cost?

In finding that FortisAB's design standards did not result in unduly discriminatory electric distribution service and cost, the AUC considered whether FortisAB's treatment of the Lanark and Sunset developments differed from other developments in the service area regarding the design standards and costs imposed on developers.

The fundamental issue was whether there was a rationale or logic and evidence to justify the differential charges between customers.

FortisAB updated its UEDS Manual on January 1, 2020, to reflect the criteria for requiring 200 amp service and specify additional options for ongoing approvals of 100 amp service. FortisAB based the requirement on the size of the residence. An exception from the requirement to install the 200 amp service was included if a load calculation sheet for the planned home is provided to prove that 100 amp service will be adequate.

The Melcor Entities argued that the standards lead to unduly discriminatory electric distribution service and cost and that the exceptions are unduly preferential to builders/developers. The Melcor Entities supported their position with the argument that the application of the 200 amp requirement appears to depend in large part on the FortisAB representative responsible for the design review. Further, as a developer and not a developer/builder, the Melcor Entities stated that they do not have information available at the subdivision stage to provide load calculations and, therefore, cannot take advantage of FortisAB's alternatives to its 200 amp requirement.

The AUC noted that, as the Melcor Entities confirmed, the lots in question are of sufficient size to trigger FortisAB's requirement for 200 amp service. Further, the AUC referred to Information Request responses provided by FortisAB that indicated that it imposed the 200 amp standard on other developers in the FortisAB service area.

The Melcor Entities' complaint also related to the imposition by FortisAB of a requirement to install cable in conduit under paved alleys instead of by direct burial, while the initial development designs contemplated direct burial in alleys. Based on the evidence provided in the proceeding indicating that conduit was required for cables installed in paved lanes in other developments, the AUC was not satisfied that the conduit design standard resulted in unduly discriminatory electric distribution service and cost. Further, the standard had been in effect for 18 years, and the Melcor Entities have complied with the conduit design standard in previous developments, as imposed by FortisAB.

Were FortisAB's Design Standards Implemented in a Manner That is Unjust, Unreasonable, Unduly Preferential, Arbitrary or Unjustly Discriminatory or Inconsistent With or in Contravention of Law?

The AUC determined that FortisAB informed affected parties of the 200 amp and conduit requirements well before signing any agreements. Based on notifications and information provided to developers, technicians, design consultants, and construction crews, the AUC was satisfied that FortisAB's 200 amp and conduit requirements were transparent and not implemented in a manner that is arbitrarily or unjustly discriminatory.

Regarding the conduit requirement, the Melcor Entities relied on the interpretation of the design standards of other utilities related to the need for conduits under paved alleys. The AUC found that FortisAB did not implement design standards in a manner that is unduly preferential to other developers and arbitrary or unjustly discriminatory to the Melcor Entities. Further, the Melcor Entities did not provide any evidence demonstrating that the challenged design standards are inconsistent with or in contravention of the law.

Conclusion

The AUC found that FortisAB's implementation of design standards did not breach its obligations under the *EUA* to provide electric distribution service that is not unduly discriminatory. The AUC further found that FortisAB did not act in a manner that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of law when imposing the design standards.

Solar Krafte Utilities Inc. Brooks Solar Farm, **AUC Decision 26435-D01-2022**
Facilities - Solar Power

In this decision, the AUC approved the application from Solar Krafte Utilities Inc. ("Solar Krafte") to construct and operate the 400-megawatt ("MW") Brooks Solar Farm (the "Power Plant"). The AUC also approved the application to construct the Zachary 997S Substation (collectively, the "Project"). The AUC did not approve the construction and operation of the Power Plant within an area of native grassland impacted by the construction ("Impacted Area").

Application

The 400-MW Power Plant will consist of 1.143 million solar panels, a substation with two 240/34.5-kilovolt ("kV"), 220-megavolt ampere transformers, and three 240-kV circuit breakers and associated equipment. The Project is located 6.5 kilometers west of the city of Brooks and the Project area is approximately 1,870 hectares ("ha").

Solar Krafte originally proposed that the Project would be located on approximately 1,578 ha of land. Solar Krafte initially did not obtain a renewable energy referral report from Alberta Environment and Parks ("AEP") for the Project. The AUC placed the proceeding in abeyance to provide Solar Krafte with additional time to obtain the referral report from AEP. AEP determined that the Project would pose an overall high risk to wildlife and wildlife habitat, based on siting and wildlife use in the area. The AUC consequently denied the initial proposal from Solar Krafte.

Solar Krafte obtained a further 291 ha of land to construct infrastructure while avoiding areas of environmental concern and maintaining the Project's capability. Following the addition of the land, AEP determined that the overall risk was lowered to a moderate level.

AUC Findings

Native Grassland

The AUC noted that AEP is responsible for the overall management and regulation of wildlife in Alberta and that the AUC is responsible for approving the construction and operation of solar power plants under the *Hydro and Electric Energy Act* ("*HEEA*") and the *Alberta Utilities Commission Act* ("*AUCA*"). S. 17 of the *AUCA* requires the AUC to consider, in addition to any other matters it may or must consider in conducting the hearing, whether the project is in the public interest, having regard to its social and economic effects, and its effects on the environment.

According to the AEP referral report, Solar Krafte did not comply with the requirement in AEP's *Wildlife Directive for Alberta Solar Energy Projects* ("*Directive*") to site solar energy projects and temporary workspaces to avoid or minimize their occurrence in important wildlife habitats and to generally avoid native grasslands, native parkland, old growth forest stands, named water bodies, valley breaks (including coulees), valleys of large permanent watercourses and the eastern slopes region.

The AUC noted that the *Directive* outlines both requirements (the Standards set out in the *Directive*) and recommendations (the Best Management Practices set out in the *Directive*) to avoid or minimize the impacts of solar power projects on wildlife and wildlife habitats. Facilities are required to meet the standards from the *Directive*, while implementation of the best management practices is not mandatory. The AUC found that Solar Krafte's proposed interpretation of the terms "disturbance" and "footprint," as limiting the *Directive*'s application of the terms to the surface area of land permanently and physically disturbed (i.e., access roads, collector line routes, and photovoltaic module piling) and the land beneath the Project solar panels, is unduly narrow and inconsistent with these other elements of the *Directive*. Rather, the AUC found, that the science behind the *Directive* requires consideration of the full impact as a result of a solar project sited on native grassland (i.e., the entirety of native grassland within the fenceline of the project as well as outside) in order to minimize effects to wildlife and wildlife habitat.

The AUC found that if the Project is sited on the Impacted Area, the Impacted Area will no longer be native grassland habitat or will be less functional in an essential way for the species that rely on this habitat. The AUC was not persuaded that the level of impact on native grassland habitat is lower if species continue to use the area of native grassland between panel rows, or if the addition of solar project infrastructure makes the Impacted Area more desirable for other species. The AUC was also not persuaded that the level of impact may be lower because the Impacted Area is not "intact" pristine grassland. The AUC consequently found that there was a high risk of significant negative effects on wildlife if the Project is sited on the Impacted Area. The AUC further found that Solar Krafte was not able to adequately mitigate the high risk to the Impacted Area and consequently found that the impacts can only be mitigated by avoiding the Impacted Area.

Weight of Wildlife and Wildlife Habitat Risk Ranking Compared to Overall Project Risk Ranking

AEP ranked the risk to wildlife and wildlife habitat in the Impacted Area as high and the overall project risk as moderate. The AUC found that while AEP's overall risk ranking is an important factor, the AUC must also consider the extent of the project's effects on wildlife and wildlife habitats that result from siting the project on native grassland.

The AUC reiterated its general view that a project's overall risk ranking from AEP is an important consideration when assessing whether a project is in the public interest. The AUC however noted that it must also take into account the specific evidence in a proceeding, which may require a determination on whether the impact on a specific wildlife feature is acceptable in the circumstances. The AUC noted that it has previously found that power plant applications are in the public interest, while also finding that aspects of those projects pose unacceptably high risks to specific wildlife features and did not approve those aspects of the project. Solar Krafte acknowledged that the AUC has the authority to approve part of a power plant application that it determines to be in the public interest while rejecting those aspects of a project that it determines are not. Accordingly, the AUC decided that it may, consistent with past practice and its legal authority, make determinations about specific environmental effects caused by the Project even though the Project may have received an overall moderate risk ranking by AEP.

Other Environmental Impacts

The AUC determined that Solar Krafte had met the Best Management Practice in the *Directive* for the avoidance of impacts to wildlife features and temporary wetlands in the areas of native habitat. The AUC acknowledged that Solar Krafte committed to investigate the use of white edges on the solar panels to reduce the risk of bird mortality. The AUC further noted that AEP may require the implementation of additional mitigation measures if it finds that bird mortalities are an issue.

The AUC imposed as a condition of approval that Solar Krafte submits a monitoring survey report, regarding bird mortality, to AEP and the AUC, in accordance with Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*.

Other Issues

The AUC further considered concerns regarding agricultural impacts, impacts on property value, and the Project's safety from effects, including solar glare.

The AUC determined that the Project was unlikely to affect the property value of agricultural land but may impact the value of residential properties. However, as the potential impact would not exceed five percent, the AUC was satisfied that the impact was acceptable.

The solar glare assessment identified nine dwellings, Highway 36, two local roads, and a railway as receptors and concluded that no solar glare is expected. Interveners noted that the solar glare assessment did not consider a helipad located approximately 2.5 kilometers west of the Project. The impact on the helipad was determined to be immaterial and manageable. Solar Krafte is committed to working with helipad users to minimize the Project's potential impact on helicopter operations on a case-by-case basis and, if needed, explore mitigating measures such as alternative flight paths or limiting the resting angle of solar arrays.

The AUC determined that the mitigating measures to address issues regarding the helipad were acceptable and that other receptors, including residential and route receptors, are predicted to have no glare from the Project.

The AUC was further satisfied that the application and the participant involvement program conducted by Solar Krafte met the requirements of Rule 007. Solar Krafte committed to mitigating noise concerns raised, particularly by limiting construction to daylight hours. The AUC determined that Solar Krafte’s management plan for construction noise will comply with Rule 012: *Noise Control* and that Solar Krafte will appropriately mitigate traffic and dust impacts during construction and maintenance.

AUC Decision

Considering the impacts on native grassland in the Impacted Area, the impact on wildlife and wildlife habitat would not be acceptable. The AUC determined that potential positive impacts could not outweigh the negative impacts of the construction and operation of the Power Plant. Accordingly, the AUC did not approve the construction and operation of the Power Plant on the Impacted Area.

Benefits of the Project include new temporary and permanent local jobs, the creation of emission-free electricity, and over $3.2 million in local tax revenue.

The AUC found that the Project's approval (excluding the Impacted Area) was in the public interest. The AUC approved the application for the construction and operation of the substation under s. 14, 15, and 19 of the *HEEA*. The AUC also approved the application for construction and operation of the Power Plant and associated facilities pursuant to s. 11 and 19 of the *HEEA.*